EEA NORTH AMERICAN GAS MARKET MODELS

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Energy and Environmental Analysis, Inc. (EEA) is widely known as an industry leader in North American energy market forecasting and analysis. Recently, EEA has been responsible, as primary technical contractor, for three of the industry's most frequently quoted long-term gas market projections:

- The 2003 National Petroleum Council study, *Balancing Natural Gas Policy – Fueling the Demand of a Growing Economy*, published in September 2003, as well as the 1999 National Petroleum Council study, *Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand*, published in December 1999.
- The GRI *Baseline Projection of U.S. Energy Supply and Demand to 2015*, published annually by the Gas Research Institute.
- The INGAA Foundation study, *Pipeline and Storage Infrastructure Requirements For a 30 TCF U.S. Gas Market*, published in January 1999 and the subsequent updates.

These and many other published natural gas market forecasts were produced from EEA's North American natural gas market models, which include:

- Gas Market Data and Forecasting System (GMDFS)
- Hydrocarbon Supply Model (HSM)

A summary of the key features of these models is presented below.

1 Overview of EEA's Gas Market Data and Forecasting System

EEA's Gas Market Data and Forecasting System (GMDFS), a nationally recognized modeling and market analysis system for the North American gas market will be used to obtain the scenario results for this project. EEA's GMDFS was developed in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions. In its infancy, the model was used to simulate changes in the gas market that occur when major new sources of gas supply are delivered into the marketplace. For example, much of the initial work with the model in 1996-97 focused on measuring the impact of the Alliance pipeline completed in 2000. The questions answered in the initial studies include:

- What is the price impact of gas deliveries on Alliance at Chicago?
- What is the price impact of increased takeaway pipeline capacity in Alberta?
- Does the gas market support Alliance? If not, when will demand support Alliance?
- Will supply be adequate to fill Alliance? If not, when will supply be adequate?
- What is the marginal value of gas transmission on Alliance?
- What is the impact of Alliance on other transmission and storage assets?
- How does Alliance affect gas supply (both Canadian and U.S. supply)?
- What pipe is required downstream of Alliance to take away "excess" gas?

Subsequently, EEA's model has been used to complete strategic planning studies for many private sector companies. The different studies include:

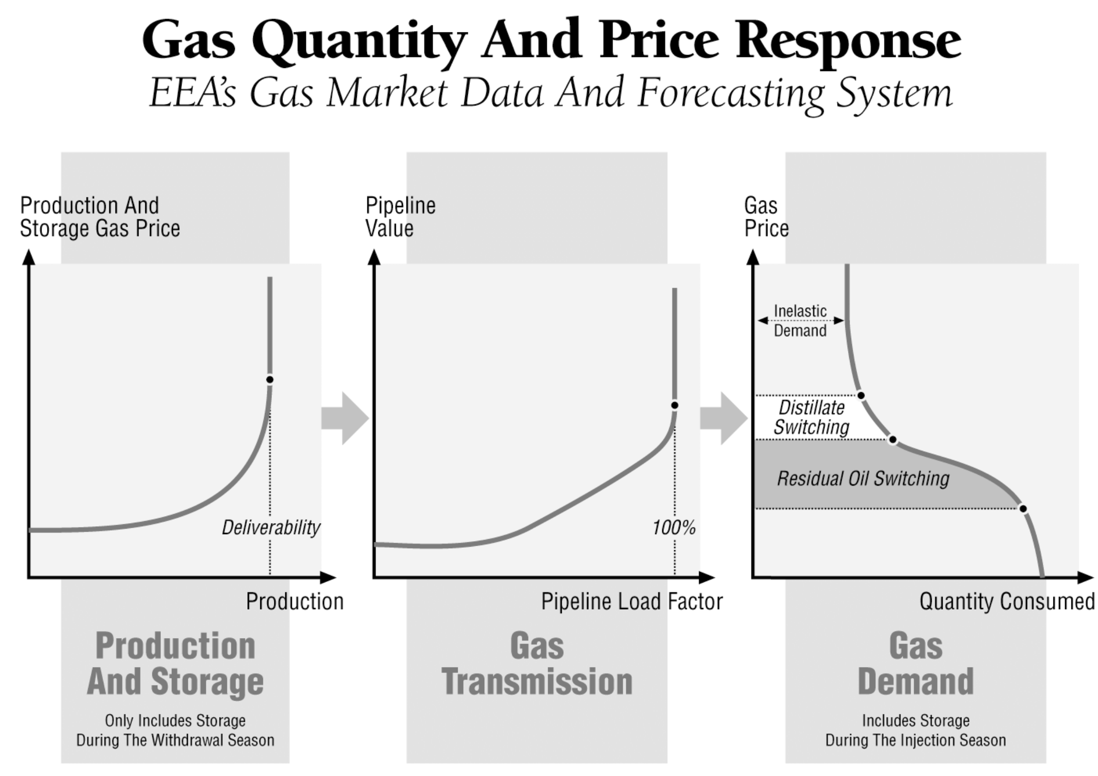
- Analyses of different pipeline expansions
- Measuring the impact of gas-fired power generation growth
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

In addition to its use for strategic planning studies, the EEA model has been widely used by a number of institutional clients and advisory councils, including INGAA, who relied on the model for the 30 Tcf market analysis completed in 1998 and again in 2004. GRI has relied on the EEA model for the GRI Baseline Projection. The model was also the primary tool used to complete the widely referenced studies on the North American Gas Market for the National Petroleum Council in 1999 and 2003.

EEA's Gas Market Data and Forecasting System is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by the user.

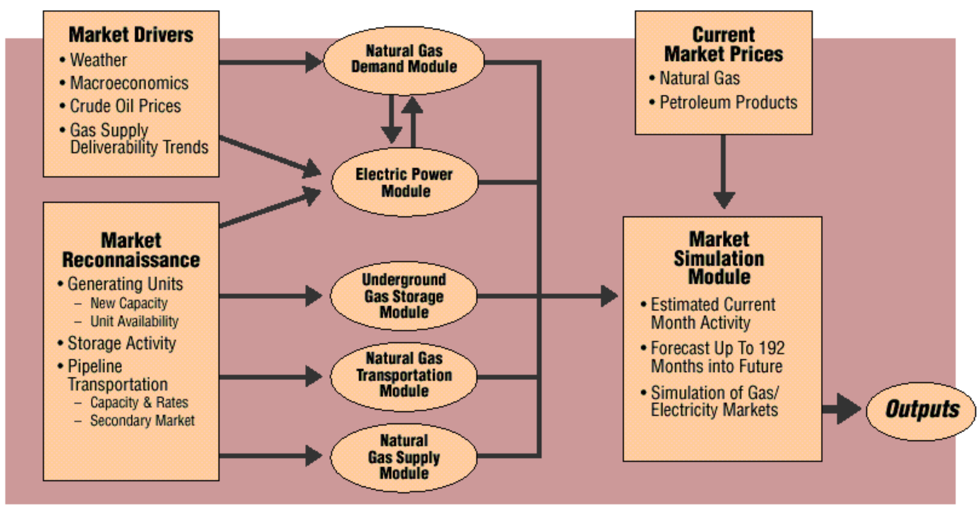
Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (Figure 1). Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and curves. Unlike other commercially available models for the gas industry, EEA does significant backcasting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

Figure 1
Supply/Demand Curves



There are nine different components of EEA's model, as shown in Figure 2. The user specifies input for the model in the "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. EEA's market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

Figure 2
GMDFS Structure



The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Figure 3 and the nodes are identified by name in Table 1. The gas supply component of the model solves for node-level natural gas deliverability or supply capability. The Hydrocarbon Supply Model (HSM), as discussed in the next section may be integrated with the GMDFS to solve for deliverability. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (i.e., end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module. A few other charts that summarize input/output and regional breakout for the EEA Model are shown as Figures 4 through 8.

The EEA model resides on a MS-Windows PC. The model relies on easy-to-use MS-Excel and MS-Access programs developed by EEA. Contact EEA at (703) 528-1900 or at inquiries@eea-inc.com for more information about the EEA modeling system.

Figure 3
GMDFS Transmission Network

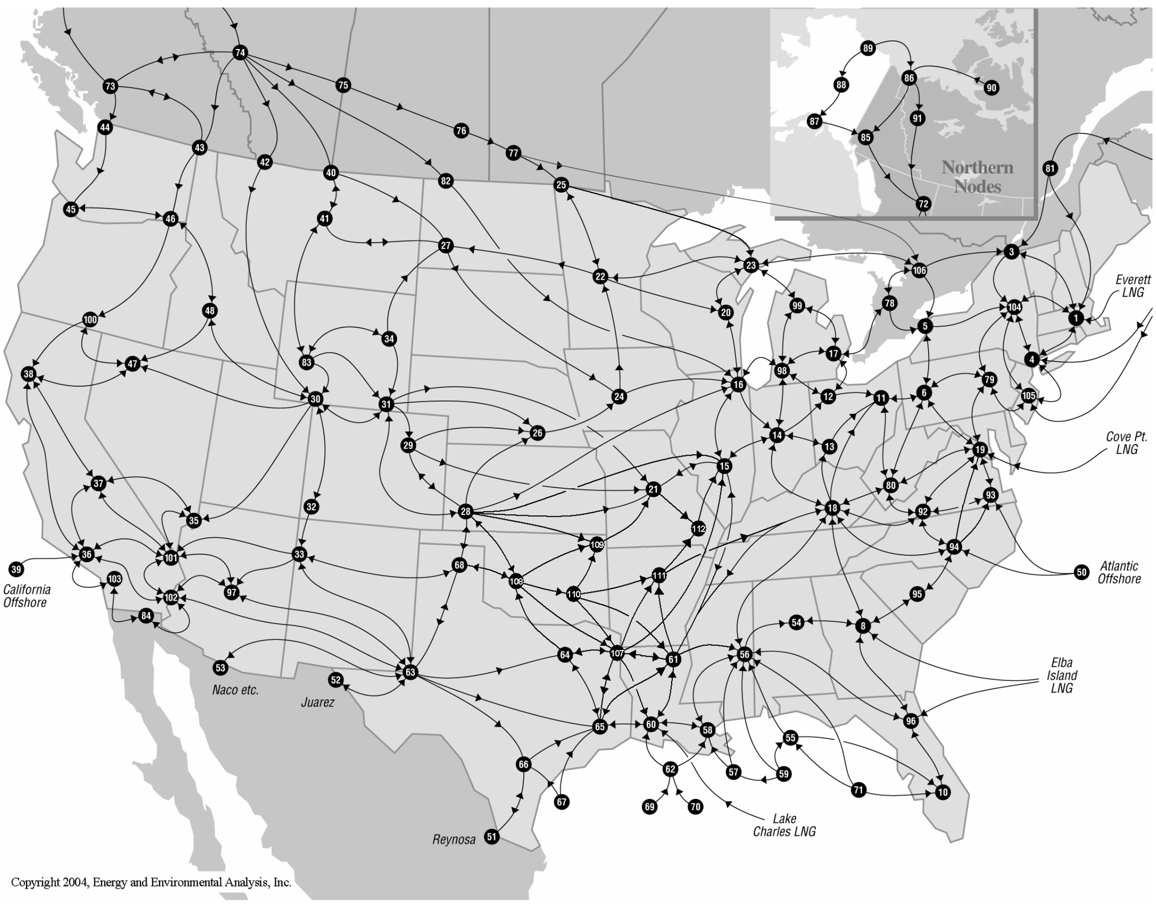


Figure 4
Model Input/Output

Model Drivers And Output

R/C/I Natural Gas Demand

DRIVERS
- Heating Degree Days
- Economic Activity
- Gas & Petroleum Prices

OUTPUT
- ► *Residential, Commercial, & Industrial Gas Demand*

Gas Supply

DRIVERS
- Base Deliverability Trends
- Gas Prices
- LNG Supply

OUTPUT
- ► *Natural Gas Production*
- ► *Wellhead and Gathering System Deliverability*

Gas Transportation

DRIVERS
- Pipeline Capacity
  - *Existing Capacity*
  - *Capacity Expansions*
  - *Operating Conditions*
- Transportation Rates
  - *FERC Tariffs*
  - *Discounted Rates*
  - *Brokered Capacity Prices*

OUTPUT
- ► *Flow on pipeline corridors*
- ► *Value of gas transmission, i.e. forecast rates based on corridor load factors.*

Electric Utility Gas Demand

DRIVERS
- Total Electricity Generation
- Non-fossil Generation
- Unit Availability
  - *New Capacity On-Line*
  - *Scheduled Downtime*
  - *Maintenance & Availability Conditions*
- Fuel Prices
- Heating & Cooling Degree Days
- Economic Activity

OUTPUT
- ► *Gas Consumed by Power Generators*

Gas Storage

DRIVERS
- Storage Capacity
- Deliverability
- Withdrawal Season:
  - *Market Demand*
  - *Usage Patterns*
  - *Cycling Requirements*
- Injection Season:
  - *Inventory Targets*
  - *Refill Patterns*
  - *Spot/Futures Price Spread*

OUTPUT
- ► *Storage Inventory*
- ► *Net Storage Injections/Withdrawals*
- ► *Net Storage Injections/Withdrawals*

Figure 5
Model Input/Output

Outputs of the Forecasting System

MONTHLY DATA	*DATA CONTENT*	*GEOGRAPHIC DETAIL OF DATA*
Gas Pricing	Delivered to Pipeline and Citygate Prices	112 Points
Pipeline Transportation	Inter-Regional Capacity Tariffs Caps Market Value of Capacity	327 Network Corridors
Gas Storage	Working Gas Capacity Inventories Injection/Withdrawal Activity	26 Storage Regions
Natural Gas Demand	By Sector (R/C/I)	34 U.S. and 7 Canada/Alaska Regions
Natural Gas Supply	Deliverability Dry Production Gas Imports/Exports Supplemental Fuels	62 U.S. and 13 Canada/Alaska Regions
Electricity Markets (U.S. Only With Explicity Imports)	Natural Gas Demand Electricity Demand Power Generation Balance Gas-fired Generation	13 "NERC" Regions

Figure 6
Demand Regions

Figure 7
Production Regions

Figure 8
Storage Regions

Table 1
GMDFS Network Node List

Node	Name	Node	Name
1	New England	57	East Louisiana Shelf
2	Everett LNG	58	Eastern Louisiana Hub
3	Quebec	59	Viosca Knoll/Desoto/Miss Canyon
4	New York City	60	Henry Hub
5	Niagara	61	North Louisiana Hub
6	Leidy	62	Central and West Louisiana Shelf
7	Cove Point LNG	63	Southwest Texas
8	Georgia	64	Dallas/Ft Worth
9	Elba Island LNG	65	East Texas (Katy)
10	South Florida	66	South Texas
11	East Ohio	67	Offshore Texas
12	Maumee/Defiance	68	Northwest Texas
13	Lebanon	69	Garden Banks
14	Indiana	70	Green Canyon
15	South Illinois	71	Eastern Gulf
16	North Illinois	72	North British Columbia
17	Southeast Michigan	73	South British Columbia
18	Tennessee/Kentucky	74	Caroline
19	MD/DC/Northern VA	75	Empress
20	Wisconsin	76	Saskatchewan
21	Northern Missouri	77	Manitoba
22	Minnesota	78	Dawn
23	Crystal Falls	79	Philadelphia
24	Ventura	80	West Virginia
25	Emerson Imports	81	Eastern Canada Demand
26	Nebraska	82	Alliance Border Crossing
27	Great Plains	83	Wind River Basin
28	Kansas	84	California Mexican Exports
29	East Colorado	85	Whitehorse
30	Opal	86	MacKenzie Delta
31	Cheyenne	87	South Alaska
32	San Juan Basin	88	Central Alaska
33	EPNG/TW	89	North Alaska
34	North Wyoming	90	Arctic
35	South Nevada	91	Norman Wells
36	SOCAL Area	92	Southwest Virginia
37	Enhanced Oil Recovery Region	93	Southeast Virginia
38	PGE Area	94	North Carolina
39	Pacific Offshore	95	South Carolina
40	Monchy Imports	96	North Florida
41	Montana/North Dakota	97	Arizona
42	Wild Horse Imports	98	Southwest Michigan
43	Kingsgate Imports	99	Northern Michigan
44	Huntingdon Imports	100	Malin Interchange
45	Pacific Northwest	101	Topock Interchange
46	NPC/PGT Hub	102	Ehrenberg Interchange
47	North Nevada	103	SDG&E Demand
48	Idaho	104	Eastern New York
49	Eastern Canada Offshore	105	New Jersey
50	Atlantic Offshore	106	Toronto
51	Reynosa Imp/Exp	107	Carthage
52	Juarez Imp/Exp	108	Southwest Oklahoma
53	Naco Imp/Exp	109	Northeast Oklahoma
54	North Alabama	110	Southeastern Oklahoma
55	Alabama Offshore	111	Northern Arkansas
56	Mississippi/South Alabama	112	Southeast Missouri

2 Supporting Data for the GMDFS

The base data that go into the GMDFS comes form several sources. Some of these are discussed below.

<u>Gas Pipeline Capacities and Flows</u>: The capacity data EEA uses for gas pipelines come mostly from the EIA's EIAGIS system. It has been supplemented by data obtained directly from the pipelines and engineering estimates made by EEA. For the recently completed NPC study, these data were reviewed and updated.

<u>New Gas Pipeline Projects:</u> EEA maintains a database on new pipeline projects. It is maintained with data from industry press releases and filings at FERC and the NEB.

<u>Existing Power Plants:</u> The data we use to model power generation comes from a commercial database sources and the Department of Energy.

<u>New Power Plants</u>: EEA tracks new power generation projects and maintains a database to support modeling efforts.

<u>Gas Consumption</u>: The raw data for gas consumption comes from EIA/DOE for the U.S. and StatisticsCanada. Due to a variety of data problems, those data are extensively processed by EEA to arrive at the gas consumption values used in our modeling. These problems include:

- Billing cycle problem: The gas consumption values published by EIA for the U.S. and by Statistics Canada are on a billing month basis, meaning that they represent the amounts consumed in the approximately 30 days proceeding the various dates in which meters were read. For example, a bill for a meter read on the 3rd of a month mostly represents consumption from the previous month while a bill for a meter read on the 30th primarily reflects consumption in the current month. Since meters are typically read throughout the month, the billed volumes will represent a mixture of consumption in the current and previous month. EEA had developed a statistical technique to use weather data to correct for this billing lag and to transform the billed volumes into "real time" consumption values for each month. Together with production and storage information, this real time consumption data is critical for understanding the monthly flows into and out of a region.
- Sampling problem with industrial demand: In addition to the billing cycle problem, monthly consumption information from EIA suffers from a sampling problem that can lead to erroneous findings if not understood and corrected. The problem arises from the limited sampling in EIA's monthly consumption survey which covers only about 25 percent of the LDCs and pipelines serving any given state. Because of the higher variability in month-to-month deliveries among

industrial facilities within a state (compared to residential and commercial loads which, for the most part, go up and down together based on the weather) the measurement errors in the state-level monthly industrial consumption statistics are very large and the data exhibit large, inexplicable monthly swings. The problems are most severe in Texas, Louisiana and California. Aside from using other sources of data, which exist only for California, the problem must be corrected by using statistically estimated values. EEA has developed such an estimating technique and has used it to analyze monthly state-level gas use and interregional gas flows.

- Under-reported consumption and large balancing items: Because of the restructuring of gas and electricity markets, the sample frames of many of the survey forms used by EIA have shrunk as a percent of the market. This has led to an increase in the sampling error of the consumption surveys, particularly in the monthly survey. The worst problem exists in the power generation and industrial sectors where gas demand has been substantially understated, causing the "balancing item" to mushroom in some recent years. EEA has adjusted the historical data in some cases to get around these problem and, so, the outputs from GMDFS will not match some published EIA consumption estimates.

Gas Prices and Basis: The primary sources of spot gas prices are the daily and weekly surveys published by various newsletters including Gas Daily, Inside FERC and Natural Gas Intelligence. EEA uses computerized price databases from all three publications in our work on contract terms and price indices. For purposes of calibrating the GMDFS, we rely on the Gas Daily database to develop historical prices by area and the basis differential between points. These data are critical to calibrating the "discount curves" that represent the market value of pipeline capacity as a function of pipeline load factor.

2.1 EEA's Updating Process

To keep the model up to date and to maintain credibility of results, EEA updates the model at the end of every month. Each month's update includes updated historical information from recent publications. EEA also adjusts model algorithms and relationships to maintain the quality of the model's "backcast", that is the agreement of model results with actual history. This assures consistency between actual history and forecast results. The historical information that EEA updates on a monthly basis is shown below.

Table 2
Information Updated Monthly

INFORMATION UPDATED MONTHLY	
ITEM	SOURCES
Economic Activity	FRB Reports
Gas Storage Activity	EIA Storage Survey, CGA Storage Survey, DOE/EIA Natural Gas Monthly, Statistics Canada
Weather	Heating and Cooling Degree Days from NOAA, DOE/EIA Monthly Energy Review, DOE/EIA Natural Gas Monthly, Statistics Canada
Oil and Coal Prices	DOE/EIA Monthly Energy Review, Wall Street Journal
Gas Production	IHS databases, MMS, state production reports
Nuclear and Hydroelectric Generation	DOE/EIA Monthly Energy Review, NRC plant update, DOE/EIA Electric Power Monthly
Historical Gas Prices	Gas Daily

In addition, EEA periodically reviews and updates historical algorithms and relationships that are built into the model. The model relationships that are periodically reviewed and updated include:

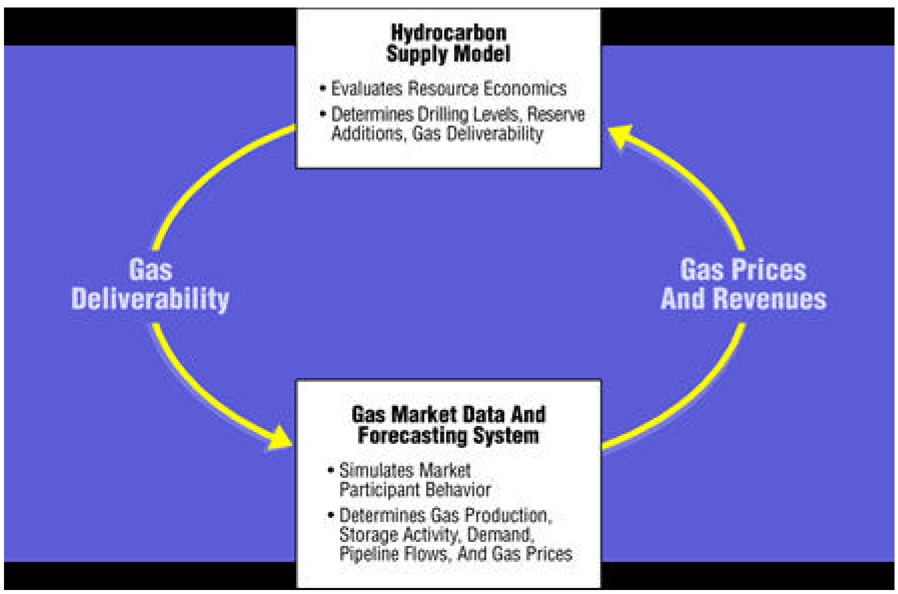
- Residential/Commercial/Industrial Gas Demand.
- Electricity Demand.
- Power Generation Dispatch.
- Pipeline Discounting Curves/Price Benchmarking.
- Gas Storage Behavior.
- Historical Gas Deliverability.

These components are reviewed and updated when they differ significantly from recent history or at least once annually.

3 Overview of EEA's Hydrocarbon Supply Model

EEA's Hydrocarbon Supply Model (HSM) is integrated with the GMDFS to provide gas deliverability projections that are a key component of the gas price solution. The primary data going from the HSM into GMDFS is natural gas deliverability and the primary data going back from GMDFS to the HSM are gas production levels and prices (Figure 9).

Figure 9
Hydrocarbon Supply Model



The HSM was developed by Energy and Environmental Analysis, Inc. in the early 1980s and has undergone many updates and improvements. The HSM is a PC-based analytical framework designed for the simulation, forecasting and analysis of natural gas, crude oil and natural gas liquids supply and cost trends in the United States and Canada. It is a process-engineering model with a very detailed representation of potential gas resources and the technologies with which those resources can be proven and produced. The degree and timing by which resources are proven and produced are determined in the model through discounted cashflow analyses of alternative investment options and behavioral assumptions in the form of inertial and cashflow constraints and the logic for setting producers' market expectations (e.g., future gas prices).

The model covers the Lower-48 United States, Alaska and Canada. The Lower-48 States are represented in 28 onshore regions (see figure below) and 11 offshore regions.

Figure 10
NPC Lower 48 Supply Regions

Alaska is divided into seven regions and Canada is divided into ten regions. All regions are further broken out into subregions or "intervals." They represent some combination of drilling depths, water depth or geographic areas. A listing of the regions and intervals used in the 2003 NPC model runs is shown below.

Table 3
HSM Regions

REVISED HSM SUPPLY REGIONS FOR NPC 2003

General Area	Region Number	Acronymn	Region Name	USGS PROVINCES	Interval 1	Interval 2	Interval 3	Interval 4	Interval 5	Interval 6	Interval 7	Interval 8
L48 ON	1	APPAL	Appalachian Basin	66, 67, 68, 69, & 70	0-5k	5-10k	10-15k	>15k				
L48 ON	2	WARRIOR	Black Warrior Basin	65	0-5k	5-10k	10-15k	>15k				
L48 ON	3	MAFLA	Mississippi, South Alabama, and Florida	50 and eastern portion of 49	0-5k	5-10k	10-15k	>15k				
L48 ON	4	MI-IL	Michigan & Illinois Basins	63 & 64	0-5k	5-10k	10-15k	>15k				
L48 ON	5	ARKLATX	East Texas, South Arkansas, & North Louisiana	48 and western portion of 49	0-5k	5-10k	10-15k	>15k				
L48 ON	6	SoLA	South Louisiana (onshore)	Louisiana portion of 47	0-5k	5-10k	10-15k	>15k				
L48 ON	7	SoTX	South Texas (onshore)	Texas portion of 47	0-5k	5-10k	10-15k	>15k				
L48 ON	8	WL	Williston, Northern Great Plains	28, 31, & 32	0-5k	5-10k	10-15k					
L48 ON	9	UINTA-PIC	Uinta-Piceance Basin	20	0-5k	5-10k	10-15k	>15k				
L48 ON	10	POWDER	Powder River Basin	33	0-5k	5-10k	10-15k	>15k				
L48 ON	11	BIGHORN	Big Horn Basin	34	0-5k	5-10k	10-15k	>15k				
L48 ON	12	WINDRVR	Wind River Basin	35	0-5k	5-10k	10-15k	>15k				
L48 ON	13	SoWeWY	Southwestern Wyoming (Green Rvr B)	37	0-5k	5-10k	10-15k	>15k				
L48 ON	14	DEN-P-L	Denver Basin, Park Basins, Las Animas Arch	39, 38, 40	0-5k	5-10k	10-15k	>15k				
L48 ON	15	RATON	Raton Basin-Sierra Grande Uplift	41	0-5k	5-10k	10-15k	>15k				
L48 ON	16	SJB-ASF	San Juan and Albuquerque-Santa Fe Rift	22, 23	0-5k	5-10k	10-15k	>15k				
L48 ON	17	WeMT	Montana Thrust Belt and SW Montana	27, 29	0-5k	5-10k	10-15k	>15k				
L48 ON	18	WY-TB	Wyoming Thrust Belt	36	0-5k	5-10k	10-15k	>15k				
L48 ON	19	PDX-GB	Great Basin and Paradox	17, 18, 19, 21, 24, 25, & 26	0-5k	5-10k	10-15k	>15k				
L48 ON	20	OR-WA	Western Oregon-Washington	4, 5	0-5k	5-10k	10-15k	>15k				
L48 ON	21	ANADARKO	Anadarko Basin	58	0-5k	5-10k	10-15k	>15k				
L48 ON	22	ARKOMA	Arkoma-Ardmore	61 & 62	0-5k	5-10k	10-15k	>15k				
L48 ON	23	NoMIDCON	Northern Midcontinent	51, 52, 53, 54, 55, 56, 57, 59, & 60	0-5k	5-10k	10-15k	>15k				
L48 ON	24	PERMIAN	Permian	42, 43, 44, 45, & 46	0-5k	5-10k	10-15k	>15k				
L48 ON	25	NoCAL	Northern California	6, 7, 8, 9	0-5k	5-10k	10-15k	>15k				
L48 ON	26	SoCAL	Central and Southern California	10, 11, 12, 13, 14, 15, & 16	0-5k	5-10k	10-15k	>15k				
L48 Off	29	EaGOM-S	Eastern GOM Offshore Shelf		Norphlet West 0–40m	Norphlet East 0-40m	Norphlet East 40–200m	EGOM Shallow 0-40m	EGOM Shallow 40–200m	EGOM Deep 0–40m	EGOM Deep 40–200m	
L48 Off	30	EaGOM-DW-s	Eastern GOM Offshore DW Shallow		Sale 181 DW	EGOM Shallow 200–400m	EGOM Shallow 400–800m	EGOM Shallow 800–1600m	EGOM Shallow >1600m			
L48 Off	31	EaGOM-DW-d	Eastern GOM Offshore DW Deep		Norphlet 200-400m	EGOM Deep 200–400m	EGOM Deep 400–800m	EGOM Deep 800–1600m	EGOM Deep Salt Roller >1600m	EGOM Deep Sale 181 >1600m		
L48 Off	32	WeGOM-S	Central & Western GOM Offshore Shelf		Plio-Pleis Shelf 0–40m	Plio-Pleis Shelf 40–200m	Miocene Shelf 0–40m	Miocene Shelf 40–200m	TX Deep Shelf 0–40m	TX Deep Shelf 40–200m		
L48 Off	33	GOM-DW-PP	C & W GOM Deepwater Plio-Pleistocene		Plio-Pleis DW 200–400m	Plio-Pleis DW 400–800m	Plio-Pleis DW 800–1600m	Plio-Pleis DW >1600m				
L48 Off	34	GOM-DW-MIO	C & W GOM Deepwater Miocene		Miocene DW 200–400m	Miocene DW 400–800m	Miocene DW 800–1600m	Miocene DW 800–1600m deep	Miocene DW >1600m	Miocene DW >1600m-deep		
L48 Off	35	GOM-DW-FB	C & W GOM Deepwater Foldbelts		Miss Fan Fb 400–800m	Miss Fan Fb 800–1600m	Miss Fan Fb >1600m	Perdido Fb 800–1600m	Perdido Fb >1600m			
L48 Off	36	Pac-Off	Pacific Offshore		OR-WA Shelf	C. CA Shelf	C. Ca Slope	S. Ca Shelf	S. Ca Slope	S.Ca Deep		
L48 Off	37	Atl-Off-N	Atlantic Offshore North		100m shallow	100m deep	500m shallow	500m deep	1000m shallow	1000m deep		
L48 Off	38	Atl-Off-M	Atlantic Offshore Central		100m shallow	100m deep	500m shallow	500m deep	1000m shallow	1000m deep		
L48 Off	39	Atl-Off-C	Atlantic Offshore South		100m shallow	100m deep	500m shallow	500m deep	1000m shallow	1000m deep		
Alaska	40	CeNoAK	North Alaska Onshore:Central		Central: Foldbelt Shallow	Central: Foldbelt Deep	Central Coastal Plain Shallow	Central Coastal Plain Deep				
Alaska	41	NPRA-AK	North Alaska Onshore: NPRA		NPRA: Foldbelt Shallow	NPRA: Foldbelt Deep	NPRA Coastal Plain Shallow	NPRA Coastal Plain Deep				
Alaska	42	ANWR-AK	North Alaska Onshore: ANWR		ANWR 1002: Foldbelt Shallow	ANWR 1002: Foldbelt Deep	ANWR 1002 Coastal Plain Shallow	ANWR 1002 Coastal Plain Deep	ANWR NON-1002: Foldbelt Shallow	ANWR NON-1002: Foldbelt Deep	ANWR NON-1002 Coastal Plain Shallow	ANWR NON-1002 Coastal Plain Deep
Alaska	43	NoAK-Off	North Alaska Offshore		Nearshore Beaufort Sea	Offshore Beaufort Shallow Water	Offshore Beaufort Deeper Water	Chukchi Sea Foldbelt	Chukchi Sea Other incl Hope Basin			
Alaska	44	CeAK	Central Alaska		Central AK Onshore							
Alaska	45	SoAK-On	South Alaska Onshore		Cook Inlet Onshore							
Alaska	46	SoAK-Off	South Alaska Offshore		Cook Inlet Offshore	Gulf of Alaska, Shumagin-Kodiak	Bering Sea Area					
Canada	49	ASM	Alberta, Saskatchewan and Manitoba		AB Plains 0-5k	AB Plains 5-10k	AB Plains >10k	AB Foothills 0-10k	AB Foothills >10k	SE AB 0-5k	SE AB >5k	Williston (Sask. & Manitoba)
Canada	50	BC	British Columbia and Liard Plateau		BC Plains 0-5k	BC Plains 5-10k	BC Plains >10k	BC Foothills 0-10k	BC Foothills >10k	Liard Plateau		
Canada	51	WeCoastCan	Canada West Coast		West Coast Basins							
Canada	52	NWC-On	Northwest Canada Onshore		MacKenzie Delta Onshore	MacKenzie Corridor incl Eagle Plain						
Canada	53	NWC-Off	Northwest Canada Offshore		Beaufort Sea 0-20 meters	Beaufort Sea >20 meters						
Canada	54	EaCanOn	Eastern Canada Onshore		Eastern Onshore							
Canada	55	Scotian	Scotian Shelf & Slope		Scotian Shelf Sable Sub-Basin	Scotian Shelf Deep Drill	Scotian Slope Deepwater	Maritimes				
Canada	56	NewF	Newfoundland Offshore		Newfound land Shelf (JDA)	Newfound land DW (Orphan)						
Canada	57	Lab	Labrador Offshore		Labrador							
Canada	58	ArcticCan	Arctic Canada		Arctic Islands							

Resources in the Hydrocarbon Supply Model are divided into three general categories: new fields/new pools, field appreciation, and nonconventional gas. The methodology for resource characterization and economic evaluation differs for each.

3.1 New Fields

New discoveries are characterized by size class. For the United States, the number of fields within a size class is broken down into oil fields, high permeability gas fields and low permeability gas fields based on the expected occurrence of each type of field within the region and interval being modeled. The fields are characterized further as having a hydrocarbon make-up containing a certain percent each of crude oil, dry natural gas, and natural gas liquids. In Canada, fields are either oil, sweet nonassociated gas or sour nonassociated gas.

The Hydrocarbon Supply Model uses a modified "Arps Roberts" equation to estimate the rate at which new fields are discovered. The fundamental theory behind the find-rate methodology is that the probability of finding a field is proportional to the field's size as measured by its areal extent, which is highly correlated to the field's level of reserves. For this reason, larger fields tend to be found earlier in the discovery process than smaller fields. The new equation developed by EEA accurately tracks discovery rates for mid- to small-size fields. Since these are the only fields left to be discovered in many mature areas of the U.S. and WCSB, the more accurate find-rate representation is an important component in analyzing the economics of exploration activity in these areas.

The find-rate equations are used in the model to predict the number of fields of a certain size that will be discovered after a given number of exploratory wells have been drilled. There are separate equations for each field-size class (e.g., size class 6 is between one and two million barrels of oil equivalent) within each depth interval, within each region. The Lower-48 portion of the model alone has over 3,000 separate find-rate equations. This is a very fine level of detail given that actual annual new field discoveries have been below 600 fields in recent years.

It is important to keep in mind that the result of the find-rate equations is a distribution of fields discovered for an increment of drilling somewhere along the discovery process. Because the large fields are more likely to be found relatively early, the distribution in the first stages of the exploration process contains a relatively high number of large fields along with the medium and small size fields. However, in the later stages of the process, the distribution contains only medium and small size fields. The results of the find-rate equations represent the expected value of field discoveries per size class. This is conceptually similar to averaging the results of a large number of Monte Carlo simulations in which the probability of discovering a field is related to its areal extent.

An economic evaluation is made in the model each year for potential new field exploration programs using a standard discounted after-tax cash flow analysis. This DCF analysis takes into account how many fields of each type are expected to be found and economics of developing each. There are about 7,000 prototype field development plans in the model for the Lower 48 U.S. that include all capital and operating costs and production timing specifications built up from historical data. The economic decision to develop a field is made using "sunk cost" economics where the discovery cost are ignored and only time-forward development costs and production revenues are considered. However, the model's decision to begin an exploration program includes all exploration and development costs.

The HSM results for new field exploration are reported in standard output tables that show the marginal economics (internal rate of return and resource cost) of exploration in each region and interval throughout the forecast. There are also outputs in Excel and Access format showing the number of fields being found, recoverable hydrocarbons discovered and recoverable hydrocarbons developed.

3.2 Appreciation to Existing Fields (Growth to Known)

Reserves in a field are proved over a period of several years. For this reason, only a portion of the gas reserves in fields found by a new field drilling increment undertaken in a year will be proved and available for production in that year. The remaining reserves will be proved in later years. The Hydrocarbon Supply Model maintains inventories of potential resources that can be proved from already discovered fields. These inventories are referred to as appreciation, growth-to-known or probables.

As the model simulation proceeds, these "probables" inventories are drawn down as the resources are proved. At the same time, the inventories of probables are increased from future year appreciation to new fields discovered during the model simulation. The methodology by which these probables inventories are proved in the model is partially time-dependent, in that "growth curves" determine the maximum rate at which probables can be proved each year after a field's discovery. The "growth curves" for the probables inventories at the start of model simulation, vary by region and field type. Other growth curves, which vary by field type and field size class, determine the rate at which reserves are proven from fields whose discovery the model simulates.

Each period, the model evaluates whether or not to prove each element in the probables inventory made eligible by the "growth curves". The producer's expected oil and gas prices are compared against the resource of the potential reserves. The resource cost of the gas in the probables inventories generally is lower than the resource cost of new fields because the new field exploratory costs are considered sunk. Because gas is added to these inventories at different times for various depths and regions, there is a distribution of prices for old field gas that can be proved in any given period. All elements meeting this criterion have a rate of return at least equal to the producer's minimum ROR and are proved in the period, unless capital constraints are binding. In that case, only a portion of each element is proved. Any of the probable resources not proved in the current period are added to the next period's inventory and will be reevaluated in that later period.

The model's initial inventory of probables is set by the user as part of the initial resource endowment for any given model case. In the 1999 NPC gas study, EEA employed the so called "cohort methodology" for analyzing historical rates of appreciation to old fields and extrapolating them into the future to estimate remaining growth potential and the number of well completions that would be needed to achieve that growth. The key element of this methodology is the fact that the recovery per well tends to decline as more and more wells are drilled in old fields. That same cohort methodology was used in the 2003 study to evaluate the nonassociated gas growth potential in the United States (outside of Appalachia where the needed data are not available) and was one of the techniques used to evaluate growth in Western Canada.

The outputs to the HSM include tables showing the inventory of probables throughout the forecast. Values are shown for crude oil, associated-dissolved gas, high perm gas, low perm gas and total NGLs. For most U.S. regions the forecasted inventory of probables declines steadily because the new field discoveries are small relative to the catalog or large, old fields with still substantial appreciation potentials. In contrast, some deepwater and Arctic regions show a increasing inventory of probables as large new field discoveries are projected to be made.

3.3 Nonconventional Gas

The Enhanced Recovery Module (or ERM) within the Hydrocarbon Supply Model, covers that portion of the resource base which falls outside the scope of the "conventional" oil and gas field discovery process dealt with elsewhere in the model. The ERM includes coalbed methane, shale gas and tight gas. These resources generally correspond to the “continuous plays” designated by the USGS in its resource assessments.

The ERM is organized by "cells", which represent resources in a specific geographic area. A cell can represent any size of area ranging from the entire region/depth interval to a single formation in a few townships of a basin. Up to three different technology cases can be specified for each cell, along with assumptions about how the market share among the technologies will change over time.

Each cell is evaluated in the model using the same discounted cashflow analysis used for new and old field investments. The ERM cells also are subject to the inertial and cashflow constraints affecting the other types of investment options in the model.

The model reports total wells drilled, reserve additions, production and dollars invested for each type of ERM cell (e.g., coalbed methane) within a region. Detailed information also is available on each cell in diagnostic tables and Excel and Access output files. The NPC cases contain 261 individual ERM cells.

3.4 Incorporation of Play-Level Conventional Resource Estimates

One of the changes made by the NPC for the 2003 study was to rely on the USGS, MMS and CGPC play-level resource assessments as the starting point the new field/new pool assessment that would be used in the model forecasts. As part of that process, EEA created three sets of processing programs to deal with each organization's data. The purpose of the processing programs were to provide a means to:

- review historical discovery data and the USGS, MMS and CGPC resource assessments in graphic and tabular form during the NPC's regional resource assessment workshops
- change the assessment for large fields (generally, one MMBOE and larger) based on the workshop findings
- extrapolate the field size distributions to the smaller fields using the assumed "linear ratio model"
- aggregate the NPC assessments by basin and region for comparisons, reviews and refinements
- reprocess the NPC assessments by HSM region to fit the findrate equations and create the regional resource base for forecasting.

Since the three organizations used different assessment methodologies and assumptions, the field size distributions were inconsistent among the groups, particularly for small fields. The use of the linear ratio model was intended to create a standardized methodology for all regions of the U.S., Canada and Mexico. This model assumes that the ratio of the ultimate number of fields in size class X to class X+1 declines as you go to smaller fields. This assumption tended to add resources to the assessment values, particularly to those of the MMS. However, the linear ratio model adds less small field resources than does the assumption of a log-geometric small field distribution in which the ratio of between successive field size is assumed to be constant.

The reprocessing of the play level data into HSM regions and intervals involved both aggregation and disaggregation. The disaggregation occurred when the play boundaries straddled the HSM regions. This occurred throughout the Gulf Coast onshore region, for state waters, in the eastern GOM, WCSB and in Northern Alaska where the HSM required an allocation among the state lands, NPRA and ANWR. A dissaggregation also was required in all areas to breakout the new fields into drilling or water depths.

On the other hand, the aggregation of plays was required to sum up the undiscovered fields in each of the HSM regions and intervals. NPC had considered preserving the individual play-level assessments (or super-plays made up of related geological packages) as "intervals" in the model. However, this idea was abandoned when GIS analysis of the historical exploratory data revealed that there was considerable overlap among play boundaries in all regions. This meant that there was no way to allocate the exploratory wells among the plays to develop reliable, history-based find-rate statistics or equations.

4 Supporting Data of the Hydrocarbon Supply Model

Beyond the resource assessment data from the USGS, MMS and CGPC discussed above, EEA has access to numerous databases that were used for the NPC model development and other analysis.

Completion-Level Production: EEA licenses the IHS completion level oil and gas production databases for the U.S. and Canada. The U.S. database contains information on approximately 300,000 U.S. completions. EEA has a system of processing this information to add certain EEA data (region, play, ultimate recovery, and gas composition) to each record. We also perform extensive quality control checks using other data sources such as the MMS completion and production data for OCS areas and state production reports. This completion-level database underlies EEA's estimates for historical and projected production that appear in our Gas Supply Review. These data were used in the NPC analysis of field appreciation and to estimate declines rates and EUR per well in the model.

Data on Non-conventional Gas: In the area of non-conventional gas, EEA has worked for many years with GRI/GTI to develop a database of tight gas, coalbed methane, and Devonian Shale reservoirs in the U.S. and Canada. Along with USGS assessment of continuous plays, the database was used to help develop the HSM's "cells" characterizing the nonconventional resource in each basin, historical nonconventional reserves estimates and typical decline curves.

Gas Composition: For various projects done for GRI, EEA has built up a database on gas compositions in the United States and has merged that data with production data to allow the analysis of net versus raw gas production. In Canada, gas composition data are obtained from provincial agencies. These data were used to develop dry gas production/reserves by region and processing costs in the HSM and to characterize ethane rejection by regions.

Field and Reservoir Data: EEA's information on oil and gas fields and pools in the U.S. come originally from the TOTL file that was licensed from Dwights. EEA has made extensive modifications to that file during the creation of the GASIS database for DOE and other projects. EEA's field and reservoir data for Canada comes from the provincial agency databases. These data are used to estimate the number and size of undiscovered fields or pools and their rate of discovery per increment of exploratory drilling. For the 2003 NPC study, additional data were obtained from the Significant Field Data Base of NRG Associates.

4.1 Upstream Cost and Technology Factors

In EEA's Hydrocarbon Supply Model, supply technologies are represented in three categories:

- Improved exploratory success rates
- Cost reductions if platform, drilling and other costs
- Improved recovery per well

These factors are input into the model by region and type of gas and represent several dozen actual model parameters.

The HSM contains base year cost for wells, platforms, operating costs and all other relevant cost items. These costs were updated for the 2003 NPC study. In addition to the base year costs, the HSM contains cost indices that adjust costs over time. These indices are partly a function of the technology drivers mentioned above and partly a function of regression-based algorithms that related cost to oil and gas prices and industry activity. As oil and gas prices and industry activity increases, the cost for seismic, drilling & completion services, casing and tubing and lease equipment goes up.

The other technology drivers affect exploratory success rates and reduce the need to drill exploratory wells. A similar adjustment is made to development success rates, but the relative effect is much smaller because development success rates are already rather high.

The technology driver that increases recovery per well is specified in the model by region and by type of gas. Generally, the improvements are specified as being greater for nonconventional gas because their recovery factors are much lower than those of conventional gas. These technology drivers can offset some of the fall off in well recoveries that are expected due to resource depletion and if set high enough could even overwhelm it.

5 SUMMARY OF KEY FEATURES

Key strengths of the HSM/GMDFS models include:

- The GMDFS provides a full supply/demand balance "solution" for each month of the forecast period, rather than relying on seasonal adjustments. A month-by-month analysis of flows and prices is essential to determining the market value of gas assets.
- The GMDFS is an integrated model that captures the interrelationships between the gas and power markets. The ability to rigorously forecast gas and power demand is key given that the electric generating sector will account for over half of the growth in North American gas demand over the next 20 years.
- The gas pipeline network design is sufficiently disaggregated to accurately describe the flow of gas at the various market centers and market nodes.
- The model determines the value of pipeline transportation capacity in the marketplace based on capacity utilization and competitive transportation options – not based on tariff rates or historical basis.

- The model can represent expected behavioral changes such as changes in storage injection and withdrawal patterns.
- Near-term wellhead deliverability is developed based on well completions at the basin level and responds dynamically to gas and oil price levels through the integration of the HSM.
- Supply results from the Hydrocarbon Supply Model include detailed well, reserve addition, decline rate and financial results that can be compared against actual data to produce credible and verifiable projections.
- The model calculates wellhead (delivered to pipeline) prices based on a full market simulation incorporating deliverability utilization, storage working gas levels, competing energy prices, weather and other factors.
- The model has undergone extensive industry review through two NPC studies and interactions with other gas industry groups.
- The model is based on extensive processing and cleaning-up of supply and demand data that avoid many of the pitfalls in the raw published data series. These data are updated regularly.